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REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	§ § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

COMMENTS FROM ENEL NORTH AMERICA, INC.

ENEL OVERVIEW

Enel North America (Enel) appreciates the opportunity to provide feedback. Enel is a multinational power company and a leading integrated player in the global power, gas and renewables markets. It is the largest European utility by market capitalization and ordinary EBITDA, and is present in over 30 countries worldwide, producing energy with over 88 GW of managed capacity. Enel distributes electricity through a network of over 1.3 million miles, and with over 73 million business and household end users globally, the Group has the largest customer base among its European peers.

Enel's renewables arm, Enel Green Power, is the world's largest renewable private player, managing around 46 GW of wind, solar, geothermal and hydropower plants in Europe, the Americas, Africa, Asia and Oceania. Enel operates in the US and Canada through two companies: Enel Green Power North America and Enel X North America. Enel Green Power North America is a leading owner and operator of renewable energy plants with a presence in 18 US states and one Canadian province. The company operates around 70 plants with a managed capacity of over 6 GW powered by wind, hydropower, geothermal and solar energy.

Enel X in North America has around 4,500 business customers, spanning more than 35,000 sites, representing approximately $10.5B in energy spend under management, approximately 4.7 GW of demand response capacity and over 70 battery storage projects that are operational and under contract.

Enel X is revolutionizing the EV charging market with its smart charging solutions deploying around 60,000 charging stations in the US.

EXECUTIVE SUMMARY OF COMMENTS

- All resources providing energy and addressing scarcity should receive the ORDC. Changes to ORDC "eligibility" will undermine the entire ERCOT market, and harm reliability.
- To bolster day ahead reliability, the commission should consider requiring wind and solar resources to submit day-ahead forecasts. Requiring a must offer commitment in the day-ahead market will not further the Commission's objectives unless it is tied to a new reliability product.
- The Commission should explore new reliability products, rather than cost allocation changes to Ancillary Services.
- The Commission should remove barriers to Demand Response to immediately support reliability needs.
- The Commission should explore out of proven market products to enhance various grid support services.

INTRODUCTION

Enel has a large investment in Texas – nearly 1 GW of operating renewable resources with an additional 2 GWs of renewables and 600 MWs of battery capacity under construction or in late development. Enel seeks to collaborate with the Commission to offer solutions and solve problems. Central to any solution are open, competitive, and technology neutral markets.

Enel believes the key problems the Commission seeks to address are (1) sending price signals to incentivize long term investment in ERCOT (2) sending price signals to procure flexible resources that compensate for fluctuations of load and generation during ramping periods and (3) addressing reliability across a variety of weather and system conditions, which is being addressed in a separate proceeding (Project 51840). These concerns arose following the catastrophic loss of life and damage caused by

Winter Storm Uri. In addition to reviewing market design, it is also essential for the Commission to examine opportunities to strengthen requirements in the natural gas system to ensure the availability of these resources, since disruptions to the natural gas system caused significant generator unavailability during Uri.

Some proposals under consideration undermine fundamental market products and could have a detrimental impact on investments in Texas. These outcomes are contrary to the Commission's objectives. Rather than fundamental market or cost allocation changes, the Commission should develop new products to achieve its objectives. Enel will detail its recommendations in these comments.

RESPONSE TO QUESTIONS

(1) What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC - based dispatchability be adjusted to specific seasonal reliability needs?

The ORDC is a scarcity product, which addresses flexibility needs driven by both load and generation. All generators producing energy and addressing scarcity should receive the ORDC. ORDC is not a long-term reliability product. Later in this filing, Enel will address new long-term reliability products the Commission may consider to incentivize investment and reliability across seasons.

Eligibility for ORDC should not be dependent on commitment into DAM. In ERCOT's energy-only market the price spreads between day-ahead and real-time are substantial enough that the ORDC would no longer offer any benefits if participants were required to bid into the day-ahead market. Any committed generation will not benefit from ORDC. Any additional generation that is not committed would still benefit.

Enel emphasizes the importance of bilateral contracts in ERCOT and the significant damage changes to ORDC eligibility would cause. In ERCOT, the majority of transactions take place in the Day

Ahead Market and bilateral forward trades. Most suppliers receive much of their revenues through these bilateral trades. In turn, real-time energy prices set expectations for bilateral trades.[1] In most bilateral trades, prices are based on ERCOT's Settlement Point Prices (SPP). SPP includes Locational Marginal Prices (LMP), ORDC, and the Reliability Deployment Price Adder (RDPA).

Radical changes to the structure of SPP would undermine nearly all bilateral trades, where the ***majority*** of transactions take place. The financial impacts to existing resources would be significant. Additionally, load may take on substantial additional costs related to the financial damages. This would erode confidence that the Texas market is stable to invest in.

As such, Enel opposes any changes to the structure of SPP, including "eligibility" for certain components of SPP. Rather than structural changes, some Market Participants have suggested the Commission may lower the $9,000 price cap. Enel believes that stakeholders could explore this change. However, this change alone would not achieve reliability and investment objectives. If the price cap were lowered, it must be accompanied by the creation of additional technology-neutral market products.

(2) Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?

No, ERCOT should not require all resources to offer into the DAM, absent the development of new reliability products. Currently, no energy only markets have must-offer requirements. If the objective is to drive investment and support long-term reliability, Enel recommends exploring the creation of a new reliability product (discussed in question 3).

If the Commission's objective is to increase transparency, increase forecasting ability, and bolster day-ahead reliability, the Commission may explore requiring wind and solar resources to provide day-ahead forecasts. These forecasts could be used in a similar process to a Reliability Unit Commitment

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[1] 2019 State of the Market Report for The ERCOT Electricity Markets https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf

process. This would improve ERCOT's insight into forecast risk and could help ensure adequate resources for the next day.

The Southwest Power Pool has a similar process, where they use the lesser of their day-ahead wind forecast and the sum of all wind economic maximum forecasts, which are essentially resource submitted forecasts, to determine reliability calculations for the day-ahead market.

(3) What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.

Enel supports exploring the creation of a monthly or seasonal reliability product to ensure reliable seasonal supply. Current ancillary services are designed to address forecast errors, and variations in load and generation. These products are not designed to ensure long-term reliability. A new reliability product should balance a) driving new investment in resources that can perform during scarcity conditions b) minimizing cost and reliability risk to load and c) rewarding resources that perform, and d) holding accountable resources that do not perform. Ancillary products are typically insufficient for driving new investment given their volatile nature and the limited number of MW procured.

The Commission should consider the reliability product capacity market designs in ISO-NE and PJM that are open to all technologies, including ISO-NE's Pay for Performance and PJM's Capacity Performance. In recent years, both ISO-NE and PJM have seen increasing levels of reliability (high reserve margins and no bulk system disruptions) with declining wholesale prices, including a very limited number of energy price spikes. For instance, since ISO-NE held their first capacity auction in 2008, wholesale energy prices have dropped nearly 75%, from $12.1B in 2008 to $3.0B in 2020.[2] Compared to this $9B decrease in energy prices, in 2020, capacity costs were $2.7B and will drop below $1B in the

[2] https://www.iso-ne.com/about/key-stats/markets

coming years. During this time, there have been nearly 12 GW of new entry in the Forward Capacity Market from energy efficiency, demand response, renewable resources and natural gas plants. Both ISO-NE and PJM markets have a capacity payment paid for by load, but load benefits through increased reliability and significantly lower risk of sustained price spikes. In return for a capacity payment, most suppliers have a must offer into the energy market, and face significant penalties for non-performance during scarcity conditions. During scarcity conditions, generators largely bear the risk of this non-performance, not load. In recent years, both markets have seen significant levels of new investments from a range of resources, including thermal, storage, renewables, and demand response.

The Commission would have considerable discretion with the procurement period for this product. In some markets, the procurement period is a year. In New York ISO, procurements are done twice annually, for summer and winter.

In addition to discretion on the timeframe for this product, the Commission could direct ERCOT to conduct rigorous analysis on all resource types to determine their resource adequacy value. Most System Operators use "Effective Load Carrying Capability" to assess the value of renewables that provide these products. ELCC or an alternative methodology should also be applied to thermal generators based on weatherization, dual fuel capability, and firm supply contracts. This type of analysis would provide the Commission with a nuanced understanding of resources ability to serve load in the most stressed conditions, and address any shortcomings. Table 1 demonstrates that thermal resources in markets such as PJM have lower performance during extreme weather conditions.[3]

[3] Modelled estimates from Murphy, et al., "A Time-Dependent Model of Generator Failures and Recoveries Captures Correlated Events and Quantifies Temperature Dependencies" (2019) Available: https://www.sciencedirect.com/science/article/pii/S0306261919311870

	Actual Avg. Capacity Value	Capacity Value at Summer Peak (Est.)	Capacity Value at Winter Peak (Est.)
Combustion Turbine	97%	93%	80%
Combined Cycle	96%	93%	92%
Coal	91%	85%	86%
Nuclear	97%	87%	98%

Implementing such a reliability product is a longer-term change, which would take months of stakeholder discussion in addition to an implementation period. Additionally, any new market products would need to be designed so as not to detract value from existing market products, which compensate resources for the significant value they add. A problem statement and clearly defined objectives would be necessary before proceeding with a change of this magnitude.

Enel does not support cost allocation changes to current Ancillary Services. Ancillary Service needs are caused by unpredictability in load, generation, and forecast error. To assign these costs to generators, or only to certain generators would be discriminatory. These types of changes would also do little to enhance reliability or encourage investment. Fundamental changes to cost allocation principles would be a detrimental signal to all market players.

(4.) Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?

Existing retail electric provider (REP) programs are limited and do not adequately capture the benefits of potentially available residential demand response. Specifically, the programs do not financially incentivize or cultivate enough participation despite the considerable adoption of residential smart technologies that would unlock access to these flexible loads. Technological advancements, such as smart thermostats, provide valuable capabilities to control these flexible residential assets during times of peak demand in a way that does not require direct customer action. Beyond ongoing programmatic financial incentives, enrollment/installation incentives will also assist in increasing the participation rate of residential customers.

The technology to truly enable residential participation is available today, and what remains is to design market programs at all levels—whether at REPs, Transmission and Distribution Utilities, or ERCOT—that can strongly incentivize participation and fully leverage the available potential.

(5.) How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?

The Emergency Response Service (ERS) program is a valuable reliability tool, and the Commission should remove the $50 million cap on ERS. This change is fully within the Commission's purview. The budgetary cap artificially restricts the desired market response. The elimination of the ERS price cap could immediately address reliability concerns and provide much more near-term solutions than others available.

During extreme weather events, demand response has proven to be a valuable resource, as demonstrated by DR's performance in February of 2021. According to ERCOT reports, "On average, fleet-level ERS Load reduction was 30%-35% above the combined fleet-level obligation during the first 12 hours after the first deployment." [4] In other words, for every MW ERCOT expected, they got 1.3 MWs. If the ERS cap had been higher, there are likely thousands of additional MWs ERCOT could have accessed. During the Uri, Enel's ERS remained deployed for the full 104 hours of EEA Level 3 system conditions, which is more hours than were required (12 hours/contract period) and the performance level was very high (99% and 100%). Overall, market wide, ERS loads overperformed against their obligation during the winter emergency event.

Similarly, PJM credited DR with helping the grid withstand the 2014 Polar Vortex, stating: "Although demand response is usually only needed by grid operators in the summer, operators also

[4] From April 2021 Demand Side Working Group "ERCOT Winter Storm Review of Demand-Side Resources and Other Related Topics". Page 6.

successfully deployed it during the power emergencies occasioned by the bitter cold 'Polar Vortex' weather in January 2014. As PJM set multiple winter peak records early that month, it called on demand response, and received more megawatts as load reductions than it could obtain as generation from all but the very largest generating stations. . . . In the midst of those challenging conditions, demand response—responding to PJM's dispatch as a wholesale market resource—helped maintain the reliability of the system."[5]

Demand response also lowers energy bills for all customers, and Texas businesses can earn revenues from participating in demand response that will make them more competitive in the global economy. Of the $50M currently spent on ERS, that is returned to Texas customers in the form of direct payments for participation. With high demand response penetration in PJM, demand response saved customers there an estimated $650 million in a single week.[6] Investing in demand response in Texas will yield increased reliability and lower energy bills.

Currently, demand response resources only amount to roughly 2.5 GW relative to ERCOT's 75 GW of peak demand, about 3%. In comparison, in PJM, demand response is nearly 7% of peak load in the current delivery year.[7]

With load increasing year after year, overall demand response resources should also meaningfully increase in turn to provide needed stability and reliability during times of peak demand. Enel supports Advanced Energy Management Alliance's comments, which call for the PUCT to set a goal of developing demand response programs that total at least 10% of system peak load. According to a FERC assessment, Texas has achievable demand response participation of 15%, making the 10% goal

[5] (Petition For Rehearing En Banc Of PJM Interconnection, L.L.C., Electric Power Supply Ass'n v. FERC at 10-11, No. 11-1486 (D.C. Cir. July 7, 2014)

[6] https://www.ferc.gov/sites/default/files/2020-04/09-07-demand-response.pdf. Page 6.

[7] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx

achievable and reasonable.[8] Additionally, the Commission could implement a program that ramps up demand response procurement to achieve the 10% goal. If the Commission pursues a demand response goal under the current market design, demand response resource could be procured competitively to ensure they provide the greatest value and efficiency.

If the Commission at some point pursues a reliability product, such as the one Enel describes in question 3, it would not be necessary to set a demand response goal. In that scenario, demand response resources should be able to participate competitively, the same as any other resource.

In addition to removing the $ 50 million price cap and identifying demand response goals, the Commission should expand the types of product procured beyond 10- and 30-minute response times. There are resources that require a longer lead time that could provide valuable reliability support during emergencies. Some of these resources conduct industrial processes that need a longer lead time to be scaled back or shut-down, but can still be available and valuable to ERCOT. Longer lead times allow resources to finish processes to prevent damage to their product or equipment and allow them to prevent large amounts of scrap/waste, which is a significant opportunity cost. Plastic manufacturers, food producers, and chemical manufacturers are just some of the resources that would be able to participate in expanded longer-lead time programs. PJM has had success procuring 30-, 60-, and 120-minute demand response resources. In NYISO, 21-hour lead time resources are procured. Generation resources with a variety of lead times participate at ERCOT. In a technology agnostic, non-discriminatory market, load resources with longer lead times should also be allowed to participate.

(6.) How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?

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[8] A National Assessment of Demand Response Potential. https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response_1.pdf p. 82

The Commission may consider out of market contracts to support reactive supply and voltage support. In FERC-regulated markets, qualified generators are paid their cost-based revenue requirement for providing these services. The allowed costs are defined and approved by FERC. The Commission may consider implementing a similar program. In this narrow circumstance, a cost-based approach is effective. However, for other products, competitive procurement is the most efficient approach.

Market-based products could incentivize resources to provide inertia and frequency support. ERCOT already has frequency products in place. The amount of frequency procured could be increased to provide more frequency support, and incentivize resources such as batteries, which are able to provide rapid frequency report.

If the Commission stives to address uncertainty over dispatch intervals, Ramp Product may successfully address these concerns. Ramp product procures a certain amount of flexible resources during SCED intervals to ensure that the system addresses load and generation variability across dispatch intervals. MISO, and CAISO have implemented Ramp Product, and a ramp product is under development currently in SPP.

CONCLUSION

Enel appreciates this opportunity to provide comments and looks forward to working with the Commission and other interested parties.

Respectfully submitted,

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